NSPS OOO00a and Other Oil and Gas Regulatory Updates

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Introduction

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- Followed NSPS OOOO development since its first proposal in 2011.
- Instructor for many oil and gas focused courses, including many workshops and courses on NSPS OOOO.
- Joined Trinity in 2007 based out of the Albuquerque, NM and Austin, TX offices.
Evolution of Trinity Consultants

1974
> One person, one office
> Air quality specialty

2015
> More than 500 employees
> 39 offices nationwide, plus Canada, the UK, China, and the Middle East
> Environmental consulting services, air quality focus
> ISO 9001 quality management system, certified in Dallas HQ
Trinity’s Services & Products

- Environmental Consulting & Auditing
- EH&S Training
- EH&S Information Management Solutions - T3
- EH&S Software - breeze
- EH&S Staffing – On Demand Environmental
- Occupational Health Science for Pharmaceuticals - SafeBridge Consultants, Inc.
Disclaimer

• Presentation is based on a *proposed* regulation;
• Air quality regulations are a dynamic field – things we cover today will likely change;
• Our understanding of issues covered today may evolve; and
• The views expressed here do not represent the views of Trinity Consultants’ clients.
What not to expect from the course...

• Absolute answers to everything!
Something to keep in mind...
Agenda

• Section 1: Overview of New Source Performance Standards (NSPS)
• Section 2: Proposed Revisions to NSPS OOOO
• Section 3: Proposed NSPS OOOOa
• Section 4: Proposed “adjacency” for Oil and Gas Sources
• Section 5: Control Technique Guidelines
• Section 6: Indian Lands Federal Implementation Plan (FIP)
August 18, 2015- New and Modified Regulations Proposed

• Modified NSPS OOOO

• New NSPS OOOOa
  
  – “Next Generation Compliance”

• Source Determination Rule for Oil and Gas Sources

• Draft Control Techniques Guidelines (CTGs)

• Indian Lands “Federal Implementation Plan”
Section 1
Overview of NSPS
New Source Performance Standards (NSPS)

<table>
<thead>
<tr>
<th>New Source Performance Standards</th>
</tr>
</thead>
<tbody>
<tr>
<td>Criteria Pollutants (e.g., VOC, NOx, CO, PM, SO2)</td>
</tr>
<tr>
<td>Affected facilities at all types of sites</td>
</tr>
<tr>
<td>Only regulates New, Modified, or Reconstructed Sources</td>
</tr>
<tr>
<td>Proposal date is effective date.</td>
</tr>
</tbody>
</table>

Note: the definition of “new,” “modified” and “reconstructed are critical when determining NSPS applicability!
National Emission Standards for Hazardous Air Pollutants (NESHAP) – NOT NSPS

<table>
<thead>
<tr>
<th>Hazardous Air Pollutants (e.g., Formaldehyde, Benzene, Toluene, etc.)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Affected facilities at “major” or “area” [e.g., minor] sources</td>
</tr>
<tr>
<td>Regulates both new and existing sources</td>
</tr>
<tr>
<td>Proposal date is effective date.</td>
</tr>
</tbody>
</table>

Note: More stringent requirements for new sources than existing sources, and more stringent requirements for major sources than area sources.
General NSPS Requirements

• Applies only to “new, modified or reconstructed sources”. Not existing.
  – These definitions and concepts are tricky
• Requirements typically consist of:
  – Emission limitations
  – Performance testing (e.g., stack testing)
  – Parametric and/or emissions monitoring
  – Recordkeeping
  – Notifications
  – Reporting
• The rules typically apply to the owner/operator
• Engine manufacturers have requirements
NSPS Subpart A – Notification and Reporting Timeline Handout 1
Construction/Affected Facility Definitions

• **Construction** - fabrication, erection, or installation of an affected “facility”

• **Affected facility** - with reference to a stationary source, any apparatus to which a standard is applicable
  – e.g., an engine vs. a compressor
  – e.g., a storage tank vs. gas well completion

• Relocating an affected facility is **not** construction, modification, or reconstruction under NSPS and does not trigger the rule
  – Permitting may be required at the new site
Modification Definition

• Any physical or operational change to an existing *facility* (e.g., the engine) which results in an increase in the emission rate of any pollutant to which a standard applies (40 CFR 60.14)
“increases the amount of any air pollutant”

- HOURLY emissions rate change (40 CFR §60.14(b))
- Interpreted as increase in short-term potential emissions
- Increasing hours of operation alone without an increase in hourly emissions rate does not constitute a modification (40 CFR §60.14(e)(3))
Modification Details

“to which a standard applies”

• An increase in emissions of a pollutant not regulated by the NSPS Subpart is not a modification

• Applicability is pollutant-specific: The only applicable sections of an NSPS Subpart are those which regulate the pollutant whose emissions increased due to the modification. (40 CFR 60.14(a))
NSPS Modification Exemptions

• Routine maintenance, repair and replacement
• An increase in production rate without a capital expenditure
  – Examples – tanks, engines, compressors
• An increase in hours of operation
• Use of an alternative fuel or raw material if source could accommodate it prior to the standard
• Addition of air pollution control device
• Change in ownership
Capital Expenditure per Subpart A

- Capital expenditure means an expenditure for a physical or operational change to an existing facility which exceeds the product of the applicable “annual asset guideline repair allowance percentage” specified in the latest edition of Internal Revenue Service (IRS) Publication 534 and the existing facility's basis, as defined by section 1012 of the Internal Revenue Code. However, the total expenditure for a physical or operational change to an existing facility must not be reduced by any “excluded additions” as defined in IRS Publication 534, as would be done for tax purposes.
NSPS VVα Applicability through NSPS O000

- NSPS Subpart O000 gas processing plant fugitives are addressed through Subpart VVα
- Addition or replacement of equipment for the purpose of process improvement which is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.
- Process improvement means routine changes:
  - Safety and occupational health requirements,
  - Energy savings,
  - Ease of maintenance and operation,
  - Correction of design deficiencies,
  - Bottleneck removal,
  - Changing product requirements, or
  - Environmental control.
Reconstruction Definition

• The replacement of components of an existing facility...
  – ...to such an extent that the fixed capital cost of the new components exceeds 50% of the fixed capital cost that would be required to construct a comparable entirely new facility,

• “Fixed capital costs” = capital needed to provide all the depreciable components
  – ...and it is technologically and economically feasible to meet applicable standards

• Effects on emissions are not considered
Timing/Aggregation Issues

• Do a series of projects at a given unit need to be aggregated together for reconstruction cost calculations?
  – Over what period?
• General guidance: under the current wording of Section 60.15, costs for non-routine renovations must be aggregated stemming from what may be viewed objectively as a single planning decision
• Some subparts (e.g., NSPS Subparts J and Ja) specify a specific period over which projects are to be aggregated
• Continue to review EPA guidance on this issue as specific projects arise
  – Some EPA guidance is contradictory on this issue
Section 2: Revised Proposed NSPS

OOOOO
Oil and Gas per EPA – Handout 2

Oil and Natural Gas Operations

Oil and natural gas systems encompass wells, gas gathering and processing facilities, storage, as well as transmission and distribution pipelines. These components are all important aspects of the process of getting natural gas out of the ground and to the end user.

- **Production & Processing**
  1. Drilling and Well Completion
  2. Producing Wells
  3. Gathering Lines
  4. Gathering and Boosting Compressors
  5. Gas Processing Plant

- **Transmission & Storage**
  6. Transmission Compressor Stations
  7. Transmission Pipeline
  8. Underground Storage

- **Distribution (not covered by these rules)**
  9. Distribution Mains
  10. Regulators and Meters for:
      a. City Gate
      b. Large Volume Customers
      c. Residential Customers
      d. Commercial Customer

**Source:** Adapted from American Gas Association and EPA Natural Gas STAR Program
Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011 and on or before September 18, 2015. 
- Compliance with NSPS OOOOa is compliance with NSPS OOOO.
Subpart OOOO Affected Facilities

- *This is a VOC rule but NOT a methane rule!*
- Each natural gas well that is hydraulically fractured
- Each centrifugal compressor using wet seals
- Each reciprocating compressor
- Each continuous bleed natural-gas driven pneumatic controller
- Each storage vessel with a >6 T/yr VOC PTE
- Group of equipment (pump, pressure relief device, open-ended valve or line, valve, and flange or other connector in VOC or wet gas service), within a process unit located at onshore natural gas processing plants
- Sweetening units located at onshore natural gas processing plants
Affected Facility Exceptions

- Pneumatic controllers with a natural gas bleed rate ≤6 scfh not at gas processing plants are not affected
- Intermittent pneumatic controllers are not affected
- Centrifugal compressors using dry seals are not affected
- Centrifugal and reciprocating compressors located at a well site are not affected
  - Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.
## Subpart OOOO Applicability

<table>
<thead>
<tr>
<th>NSPS OOOO Affected Facility</th>
<th>Production (Well Site)</th>
<th>Gathering</th>
<th>Gas Processing</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas Well</td>
<td>X</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Centrifugal Compressors</td>
<td></td>
<td>X</td>
<td>X</td>
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<tr>
<td>Reciprocating Compressors</td>
<td></td>
<td>X</td>
<td>X</td>
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<tr>
<td>Pneumatic Controller</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Storage Vessels</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
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<tr>
<td>Equipment Leaks</td>
<td></td>
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<td></td>
<td>X</td>
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<tr>
<td>Sweetening Units</td>
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<td>X</td>
</tr>
</tbody>
</table>
### NSPS OOOO Compliance Schedule

<table>
<thead>
<tr>
<th>NSPS OOOO Affected Facility</th>
<th>Standard</th>
<th>Compliance Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydraulically fractured wildcat and delineation wells</td>
<td>Completion combustion</td>
<td>October 15, 2012</td>
</tr>
<tr>
<td>Hydraulically fractured low pressure non-wildcat and non-delineation wells</td>
<td>Completion combustion</td>
<td>October 15, 2012</td>
</tr>
<tr>
<td>Other hydraulically fractured wells</td>
<td>Completion combustion</td>
<td>Before 1/1/2015</td>
</tr>
<tr>
<td>Other hydraulically fractured wells</td>
<td>REC and completion combustion</td>
<td>After 1/1/2015</td>
</tr>
<tr>
<td>Centrifugal compressors with wet seals</td>
<td>95% reduction</td>
<td>October 15, 2012</td>
</tr>
<tr>
<td>Reciprocating compressors</td>
<td>Change rod packing</td>
<td>October 15, 2012</td>
</tr>
<tr>
<td>Pneumatic controllers at NG processing plants</td>
<td>Zero bleed rate</td>
<td>October 15, 2012</td>
</tr>
<tr>
<td>Pneumatic controllers between wellhead and NG processing plants</td>
<td>6 scfh bleed rate</td>
<td>October 15, 2013</td>
</tr>
<tr>
<td>Group 2 and 1 Storage Vessels</td>
<td>95% reduction</td>
<td>April 15, 2014/2015</td>
</tr>
<tr>
<td>Equipment Leaks</td>
<td>LDAR program</td>
<td>October 15, 2012</td>
</tr>
<tr>
<td>Sweetening Units</td>
<td>Reduce SO₂ as calculated</td>
<td>October 15, 2012</td>
</tr>
</tbody>
</table>
NSPS OOOO: Initial and Continuous Monitoring Requirements for CVS

- 60.5411 and 60.5416: install a flow indicator at the inlet to the bypass device.
- Must have audible and visual alarm and initiate remote alarm if the stream is diverted away from the control device.
- Maintain records of each alarm.
- Also included in NSPS OOOOa.
NSPS OOOO: Control Devices for Storage Vessel and Centrifugal Compressors

• Reduce concentration of TOC in exhaust gases at the outlet to $\leq 600$ ppmv (is currently 20 ppmv).

• Non-manufacturer certified combustion control devices will now have performance testing requirements.

• Manufacturer tested combustion control devices must not have visible emissions more than 1 minute of a 15 minute period, checked monthly.
  – Currently 2 minutes during 1 hour observation, quarterly

• Requirements also added to NSPS OOOOa (and also apply to pneumatic pumps).
NSPS OOOO: Control Devices for Storage Vessel and Centrifugal Compressors

• Control equipment used to control emissions from storage vessels or centrifugal compressors must undergo periodic performance testing no later than 60 months after startup or since the last test.
NSPS OOOO: Definitions

• Added a definition of “Capital Expenditure” (same definition found in proposed OOOOa, discussed later); and

• Modified “Group 2” storage vessel as constructed after April 12, 2013 and on or before [date of publication in the Federal Register].
Section 3: Proposed NSPS OOOOa

• Proposed rules can change drastically from version to version
• There is no guarantee when (or if) any rule will become “final”
• This will be an evolving issue
60.5360a: What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of methane, VOC and SO2 emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification or reconstruction after September 18, 2015. The effective date of this rule is [date 60 days after publication of the final rule in the Federal Register].
Definition of the Source Category [60.5430a]

Crude oil and natural gas source category means:

1. Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline; and

2. Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the city gate.
Definition of Custody Transfer
[60.5430a]
Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.
<table>
<thead>
<tr>
<th>NSPS OOOO Affected Facility</th>
<th>Production (Well Site)</th>
<th>Gathering</th>
<th>Gas Processing</th>
<th>Transmission</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydraulically Fractured Well (with GOR &gt;300 scf/bbl)</td>
<td>X</td>
<td></td>
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<tr>
<td>Centrifugal Compressors</td>
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<td>X</td>
<td>X</td>
<td>X</td>
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<tr>
<td>Reciprocating Compressors</td>
<td></td>
<td>X</td>
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<td>X</td>
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<tr>
<td>Pneumatic Controller</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
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<tr>
<td>Pneumatic Pumps</td>
<td>X</td>
<td>X</td>
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<td>X</td>
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<tr>
<td>Storage Vessels</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
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<tr>
<td>Equipment Leaks</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
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<tr>
<td>Sweetening Units</td>
<td></td>
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<td>X</td>
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<tr>
<td>NSPS OOOO or OOOOa Affected Facility</td>
<td>Standard</td>
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<tr>
<td>Hydraulically fractured wildcat and delineation wells</td>
<td>Completion combustion, LDAR program</td>
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<tr>
<td>Hydraulically fractured low pressure non-wildcat and non-delineation wells</td>
<td>Completion combustion, LDAR program</td>
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<tr>
<td>Other hydraulically fractured wells</td>
<td>REC and completion combustion, LDAR Program</td>
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<td></td>
<td></td>
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<tr>
<td>Centrifugal compressors with wet seals</td>
<td>95% reduction</td>
<td></td>
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<tr>
<td>Reciprocating compressors</td>
<td>Change rod packing or <strong>collect vented emissions</strong></td>
<td></td>
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<tr>
<td>Pneumatic controllers and pneumatic pumps at NG processing plants</td>
<td>Zero natural gas bleed rate</td>
<td></td>
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<tr>
<td>Pneumatic controllers not at NG processing plants</td>
<td>6 scfh natural gas bleed rate</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pneumatic pumps not at NG processing plants</td>
<td>95% reduction (if control device in place) or annual certification</td>
<td></td>
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<tr>
<td>Storage Vessels</td>
<td>95% reduction</td>
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<tr>
<td>Equipment Leaks at gas plants, and new or modified compressor stations</td>
<td>LDAR program</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Sweetening Units</td>
<td>Reduce SO₂ as calculated</td>
<td></td>
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</tbody>
</table>
Wellhead Requirements
Well Affected Facility [60.5360a(a)]

• A single well that conducts well completion following hydraulic fracturing or refracturing and has a GOR >300 scf/bbl.
  – Wells completed following refracturing using a reduced emission completion (REC) are not affected facilities requiring the use of a REC, however;
  – Hydraulic fracturing of a well constitutes a modification of the well site and will be subject to the leak detection requirements for well sites.
  – Refracturing of a well does not affect the modification status of other equipment.
Definition of Well Site [60.5430a]

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purpose of the fugitive emission standards at 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids or produced water from wells not located at the well site (e.g., centralized tank batteries).
Wellhead Requirements – 4 in all

1. **REC** - Perform reduced emissions completions/green completions:
   - During the **initial flowback** stage, route the **flowback** into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.
   - During the **separation flowback** stage, route all **recovered liquids** from the separator to one or more well completion vessels or storage vessels, re-inject the liquids into the well or another well or route the recovered liquids to a collection system. Route the **recovered gas** from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is infeasible to route the recovered gas as required above, route gas to combustion device. If, at any time during the separation flowback stage, it is not technically feasible for a separator to function, you must comply with requirements for initial flowback.
Wellhead Requirements – 4 in all

2. Route to Sales - Route salable quality gas to the gas flow line as soon as practicable. If salable gas cannot be routed to a flow line, follow requirements found in (3).

3. Completions Combustion - Capture and direct recovered gas that cannot be directed to the flow line to a completion combustion device (unless risk of fire or explosion). It must be equipped with a reliable continuous ignition source.

4. General Duty - Maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.
Flowback - Definitions

**Flowback** means the process of allowing fluids and entrained solids to flow from a natural gas well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a natural gas well during the flowback process.

The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.
Flowback Stages - Definitions

- **Initial flowback** stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

- **Separation flowback** stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.
Recovered Gas/Liquids - Definitions

• Recovered gas means gas recovered through the separation process during flowback.

• Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.
## Standards for Hydraulically Fractured Wellheads [60.5375a]

<table>
<thead>
<tr>
<th>Hydraulically Fractured Well Operation</th>
<th>Control Option 1 (REC)</th>
<th>Control Option 2 (Sales)</th>
<th>Control Option 3 (Combust)</th>
<th>Control Option 4 (General Duty)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wildcat and Delineation</td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Low Pressure non-wildcat and non-</td>
<td></td>
<td></td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>delineation</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>All Other Wells with a GOR &gt;300 scf/bbl</td>
<td>X</td>
<td>X</td>
<td>X (if 1 and 2 are infeasible)</td>
<td>X</td>
</tr>
</tbody>
</table>
Well Completion “To-Do” [60.5420a]

• Submit advance notification at least 2 days prior to the commencement of completion of a hydraulically fractured well affected facility
  – State-level notifications, if required, meet this requirement

• Notification includes:
  – Location
  – API Well Number
  – Planned date of beginning of flowback
Well Completion “To-Do” [60.5420a]

• During completion, keep a daily log book with:
  – Location
  – API Well Number
  – Date and time of the onset of flowback following HF
  – Date and time of each attempt to direct flowback to a separator;
  – Date and time of returning to the initial flowback stage
  – Date and time the well was shut in and flowback equipment permanently disconnected OR the startup of production;
  – Duration of flowback
  – Duration of venting
  – Duration of recovery to flow line
  – Duration of combustion
  – Reasons for deviations from the standard
Well Completion “To-Do” [60.5420a]

• For wellheads subject to both REC and completion combustion equipment, a digital photograph must be taken that contains:
  – Date of photograph
  – Longitude and latitude of the well site embedded within or stored with the photograph (or separate GIS device visible in frame)
  – Picture of equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to gas flow line, and the completion combustion device connected to and operating at each completion operation
**So... you plan to hydraulically fracture a well?**

**Before** starting your project, notify environmental personnel at least 72 hours prior to completion and include the following:

- Expected GOR
- Well API Number
- Well Name
- Well Location
- Planned Completion Date
- Planned Date of Beginning of Flowback

**During** flowback (once a separator can function), flaring is not allowed (unless there is an exemption e.g., local burn ban, etc.). The following information must be logged during flowback:

- Location
- API Well Number
- Date and time of the onset of flowback following HF
- Date and time of each attempt to direct flowback to a separator;
- Date and time of returning to flowback without use of a separator
- Date and time the well was shut in and flowback equipment permanently disconnected OR the startup of production;
- Duration of flowback
- Duration of venting
- Duration of recovery to flow line
- Duration of combustion
- Reasons for venting, if applicable

**After** completion, route the gas to a sales line as soon as practicable.

*Remember to always safely maximize resource recovery and minimize releases to the atmosphere!*
Who to Notify?

• Most states have a method to accept these notification – otherwise EPA region office
• If unsure in a state, recommend notifying both EPA regional office and state
• Annual Report must be certified by a “Certifying Official”
Compressor Requirements
Centrifugal Compressors with Wet Seals [60.5365a(b), 60.5380a]

- Centrifugal compressors equipped with wet seals (not at a well site facility) constructed, modified or reconstructed [>8/23/2011]:
  - Reduce VOC emissions from each wet seal fluid degassing system by ≥95.0 percent
  - If using a control device, equip with specified cover and connect through a closed vent system to a control device
  - Conduct initial inspection
  - Install and operate continuous parameter monitoring system (CPMS)
  - Initial performance test required
Centrifugal Compressors with Wet Seals [60.5365a(b), 60.5380a]

• Centrifugal compressors with wet seals at a well site or an adjacent well site servicing more than one well site are exempt.

• Centrifugal compressors with wet seals located between the well site up to the city gate are potentially subject.

• Reduce methane and VOC emissions from wet seal fluid degassing by 95% or more.
Standards for Reciprocating Compressors

• Applies to reciprocating compressors not located at a well site constructed, modified, reconstructed [>8/23/2011]

• Primary requirement is to replace the rod packing OR route emissions to a process

• You can choose to replace rod packing before either of the following occur:
  – the compressor has operated for 26,000 hours; or
  – 36 months from the last replacement.
Reciprocating compressors at a well site or an adjacent well site servicing more than one well site are exempt.

• Reciprocating compressors located between the well site up to the city gate are potentially subject.

• Change rod packing every 26,000 hours of operation or every 36 months; or

• Collect the methane and VOC emissions using a rod packing collection system which operates under negative pressure.
Continuous Bleed
Pneumatic Controller
Requirements
Definitions

> Continuous Bleed
  ❖ Means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

> Natural gas driven pneumatic controller
  ❖ Means a pneumatic controller powered by pressurized natural gas.
Continuous Bleed Pneumatic Controllers [60.5365a(d), 60.5390a]

- Continuous bleed natural gas pneumatic controllers located between the wellhead and the city gate (not at gas processing plants) constructed, modified or reconstructed after 10/15/2013 must have a bleed rate $\leq 6$ scf/h.
  - If a higher bleed device is required, it must be tagged with the month/year of installation.

- Continuous bleed pneumatic devices located at gas plants must have a bleed rate of 0 scf/h.
  - Tag all continuous bleed pneumatic devices.
Storage Vessel Requirements
Storage Vessels – Affected Facilities

[60.5365a(e)]

- A storage vessel with the potential to emit 6 tpy VOC (not methane, as required in other parts of the rule) or more based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section.
- Take into account legally and practically enforceable limits in a permit or other requirement.
- Take credit for vapor recovery as long as the cover and closed vent system requirements are followed.
Definition: Maximum Average Daily Throughput [60.5430a]

Means the earliest calculation of daily average throughput during the 30-day [potential to emit] evaluation period employing generally accepted methods.

[Unchanged]
Storage Vessel Definition

*Storage vessel* means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. Two or more storage vessels connected in parallel are considered equivalent to a single storage vessel with throughput equal to the total throughput of the storage vessels connected in parallel. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395(f) until such time as such tank or other vessel has been returned to service.
Storage Vessel Definition

- Storage vessels that contain crude oil, condensate, produced water or “intermediate hydrocarbon liquid”
- For the purposes of this subpart, the following are **NOT** considered storage vessels:
  - Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel since the original vessel was first located at the site.
  - Process vessels such as surge control vessels, bottoms receivers or knockout vessels.
  - Pressure vessels designed to operate in excess of 204.9 kilopascals (29.7 psi) and without emissions to the atmosphere.
Storage Vessels [60.5395a]

• New, modified or reconstructed storage vessels determine the PTE within 30 days after startup.
• If ≥6 tpy VOC per tank, reduce emissions by 95%.
• If emissions are ≥6 tpy VOC per tank, control emissions within 60 days from startup of production; OR
• Maintain uncontrolled emissions less than 4 tpy for 12 consecutive months and evaluate monthly based on the average monthly throughput.
  – If a well feeding a tank in this category (i.e. <4 tpy) is hydraulically fractured, install controls as soon as liquids are routed to the tank; or
  – If emissions > 4 tpy for any other reason, install controls within 30 days.
Storage Vessels
[60.5395a(c)]

• If an affected facility is removed or returned to service, provisions remain the same as currently codified.
Definition: Startup of Production [60.5430a]
Means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or water.
[Unchanged]
Pneumatic Pumps
Pneumatic Pumps [60.5365a(h), 60.5393a]

- **Natural gas pneumatic pumps** located between the wellhead up to the city gate (except at gas processing plants) must reduce emissions by 95% *if a control device is in place*.
  - Tag with month and year of installation

- Natural gas pneumatic pumps located at a gas processing facility must have a bleed rate of 0 scf/h *if a control device is in place*.
  - Tag with month and year of installation

- If no control device is in place, submit a certification of sites with uncontrolled pneumatic pumps.
Definition: Natural Gas Driven Pneumatic Pump [60.5430a]

Means a chemical or methanol injection or circulation pump or a diaphragm pump powered by pressurized natural gas.
Pneumatic Pumps

[Preamble]

• “While the use of a new combustion device is not cost-effective, the costs appear reasonable when using an existing combustion control device that is already on site.” [p. 56626, FR Vol. 180, No. 181]

• Remember: a NSPS OOOOa pneumatic pump routed to a control device will bring CVS inspection requirements and VE requirements.
Fugitives at Well Sites and Compressor Stations

• Monitor all **fugitive emission components** with an optical gas imaging (OGI) device.
• Repair all sources of fugitive emissions.
• Develop a corporate-wide monitoring plan and a site specific monitoring plan (or one plan that incorporates all required elements in 60.5397a).
• Conduct surveys semi-annually after the initial survey.
Definition: Fugitive Emission Component [60.5430a]

Means any component that has the PTE fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches, or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas driven pneumatic controllers or natural gas driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device’s vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.
Fugitives at Well Sites [60.5365a(i)]

• Well sites that are constructed, modified or reconstructed after the applicability date will have requirements, provided that:
  – They have a production rate ≥15 boe/day; and
  – Consist of more than just wellheads.

• Note the previously discussed definition of “well site.”
Definition of Well Site [60.5430a]

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purpose of the fugitive emission standards at 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids or produced water from wells not located at the well site (e.g., centralized tank batteries).
“Modification” to a Well Site [60.5365a(i)]

• A “modification” occurs to a well site when:
  – A new well is drilled at an existing well site; or
  – A well at an existing well site has been hydraulically fractured or refractured.
Fugitives at Well Sites [60.5397a]

• Conduct initial survey within 30 days of the first well completion at a new site; or
• Conduct initial survey for other wells at well sites prior to production phase.
• If modifying a collection of fugitive emissions at a well site, conduct survey within 30 days of the modification.
Fugitives at Compressor Stations [60.5365a(j), 60.5397a]

• **Compressor stations** that are modified, constructed or reconstructed must conduct leak surveys.
  
• Conduct survey within 30 days of startup of new compressor station; or
  
• Within 30 days of the modification.
“Modification” to a Compressor Station [60.5365a(j)]

A compressor station is modified if:
1. A new compressor is constructed at an existing compressor station; or
2. A physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.
Compressor station site means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations.
Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area or other wholesale source of gas to one or more distribution area(s).
Fugitives at Well Sites and Compressor Stations

• After two consecutive semiannual surveys demonstrate less than 1% of leaking fugitive components, detection can be reduced to annually.
• After two consecutive semiannual surveys demonstrate more than 3% of leaking fugitive components, detection will be increased to quarterly.
• This approach will require component counts at each facility.
Fugitives at Well Sites and Compressor Stations

• For any leaks found during the survey:
  – Repair during the survey and confirm repair with OGI; or
  – Repair within 15 days and re-evaluate using OGI or Method 21.
Recordkeeping for Leak Surveys at Well Sites and Compressor Stations

- Date of survey;
- Beginning and end time of survey;
- Name of operator performing survey, including training and experience of the operator;
- Ambient temperature, sky conditions and maximum wind speed;
- Deviations from the monitoring plan;
- Documentation of each source of fugitive emissions;
- One or more digital photographs of each monitoring survey; and
- The instrument used to resurvey repaired components.
Leaks and Sweetening Units
Standards for VOC Leaks

- Applies to equipment, except compressors, in VOC or wet gas service within a process unit at a natural gas processing plant.
- Process Unit - Components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.
- Comply with NSPS Subpart VVa
Natural Gas Processing Plant

• What is a “Natural Gas Processing Plant?”
  – “any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas to NGL products, or both. A JT valve, a dew point depression valve, or an isolated or standalone JT skid is not a natural gas processing plant.”
## Equipment Leaks at Gas Plants

<table>
<thead>
<tr>
<th>Component</th>
<th>Leak Definition (ppm)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Component</strong></td>
<td><strong>Leak Definition (ppm)</strong></td>
</tr>
<tr>
<td>KKK</td>
<td>O0000</td>
</tr>
<tr>
<td>Pumps in light liquid service</td>
<td>10,000 2,000</td>
</tr>
<tr>
<td>Valves in gas/vapor service</td>
<td>10,000 500</td>
</tr>
<tr>
<td>Valves in light liquid service</td>
<td>10,000 500</td>
</tr>
<tr>
<td>Connectors</td>
<td>Not subject 500</td>
</tr>
<tr>
<td>Pumps, valves and connectors in heavy liquid service; pressure relief devices in light liquid or heavy liquid service</td>
<td>AVO/10,000 AVO/10,000</td>
</tr>
</tbody>
</table>
Standards for Sweetening Units

• Applies to each onshore sweetening unit at a natural gas processing plant:
  – Emission limits remain the same as proposed rule (comply with percent reduction requirements based on sulfur feed rate and hydrogen sulfide [H2S] content of acid gas)
  – Initial performance test required
  – Monitoring of sulfur product accumulation, H2S content, and acid gas flow rate
• Facilities with design capacities less than 2 long tons per day of H2S in the acid gas are subject to recordkeeping and reporting only
General Compliance Requirements
Compliance Demonstration for Storage Vessels

• For each enclosed combustion device:
  – Conduct initial compliance test (either manufacturer or operator)
  – Install and operate a continuous burning pilot;
  – Conduct the following monthly inspections and keep records:
    • OVA inspection of the control device to ensure integrity;
    • Visual inspection to confirm the pilot is lit;
    • Method 22 (observe for 15 min., smoke not to exceed 1 min.)
      – Would replace quarterly requirement, observe for 1 hour, smoke not to exceed 2 minutes.
      – EPA is proposing this so that the visible emission requirements for both manufacturer and operator certified combustors would be the same.
Notification Requirements

- Hydraulically Fractured Wells
  - 2-day notification for completion activities
  - Also include in the annual report

- Pneumatic controllers, Storage Vessels, reciprocating compressors, fugitives at wellsites or compressor stations, pneumatic pumps
  - Only include in annual report

- Normal Subpart A notices for compliance tests (including centrifugal compressors), equipment leaks and sweetening units
“Next Generation Compliance” - Preamble

- Starts on page 56648 of the Federal Register.
- EPA is seeking comment on potential “Next Generation Compliance” options.
  - Third party verification of process and control design;
  - Third party verification of IR monitoring program;
  - Third party information reporting; and
  - Electronic reporting.
Section 4:
Source Determination
Source Determination

• Three factor source determination
  – Same two-digit standard industrial classification (SIC) code;
  – Common ownership or control; and
  – Located on one or more adjacent or contiguous properties.
• “Adjacent” is used, but never defined.
• Rulemaking stems from years of litigation and has resulted in another rule change (EPA’s Consistency Rules).
Source Determination

• EPA is proposing to clarify “adjacent” in:
  – Prevention of Significant Deterioration (PSD);
  – Nonattainment New Source Review (NNSR); and
  – Title V.

• The proposed changes will impact operations with the Major Group SIC code of 13 (Oil and Gas Extraction).
Source Determination

• EPA lists the following NAICS as potentially impacted by this rulemaking:
  – Oil and Gas Extraction 21111
  – Crude Petroleum and Natural Gas Extraction 211111
  – Natural Gas Liquid Extraction 211112
  – Drilling Oil and Gas Wells 213111
  – Support Activities for Oil and Gas 213112
  – Natural Gas Distribution 221210
  – Pipeline Distribution of Crude Oil 486110
  – Pipeline Distribution of Natural Gas 486210
Source Determination

• Option 1 (EPA’s preferred option)
  – Two or more sources share the same two-digit SIC code (Major Group 13, “Oil and Gas Extraction”);
  – Under common control; and
  – Are contiguous or are located within ¼ mile of each other.

• EPA is seeking comment on limiting the linking of sources outside of a target facility (“daisy-chaining”).
Source Determination

• Option 2
  – SIC Major Group 13 (Oil and Gas Extraction):
    – The sources are separated by a distance ¼ mile or less; OR
    – The sources are separated by a distance of more than ¼ mile and there is exclusive functional interrelatedness.
Section 5: Control Technique Guidelines (CTGs)
Control Technique Guidelines

• Apply to existing sources operating in ozone nonattainment areas classified as Moderate and above, and throughout the Ozone Transport Region (OTR).

• CTGs do not apply any requirements directly to facilities; rather, they provide recommendations for state/local agencies to consider in determining reasonably available control technology (RACT).
  – States may use different technology and approaches, subject to EPA approval via the SIP process.
## CTG Recommendations

<table>
<thead>
<tr>
<th>Source Category</th>
<th>Applicability</th>
<th>Recommendations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage Tanks</td>
<td>• PTE &gt; 6 tpy VOC</td>
<td>• 95% Control Device</td>
</tr>
<tr>
<td>Pneumatic Controllers</td>
<td>• Processing Plants</td>
<td>• Zero Bleed</td>
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<tr>
<td></td>
<td>• Production Sites</td>
<td>• Bleed Rate &lt; 6 scfh</td>
</tr>
<tr>
<td></td>
<td>Pneumatic Pumps</td>
<td></td>
</tr>
<tr>
<td></td>
<td>• Processing Plants</td>
<td>• Zero Emissions</td>
</tr>
<tr>
<td></td>
<td>• All Other Segments</td>
<td>• Vent to 95% Control Device if one exists</td>
</tr>
<tr>
<td>Compressors</td>
<td>• Reciprocating</td>
<td>• Rod Packing Replacement every 26,000 hrs/36 months</td>
</tr>
<tr>
<td></td>
<td>• Centrifugal w/ Wet Seals</td>
<td>• 95% Control Device</td>
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<td></td>
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<tr>
<td>Equipment Leaks</td>
<td>• Processing Plants</td>
<td>• LDAR – Subpart Vva</td>
</tr>
<tr>
<td></td>
<td>• All Other Segments</td>
<td>• LDAR - OGI</td>
</tr>
</tbody>
</table>

*Essentially, CTG’s recommend implementation of NSPS OOOO/OOOOa requirements at existing facilities which are subject to RACT (i.e., major sources of NOx/VOC in ozone non-attainment areas).*
Section 6: Indian Country Federal Implementation Plan (FIP)
Indian Country Permitting for O&G

- Background
  - Current Indian Country NSR Rule was promulgated July 1, 2011.
  - Requires registration of existing sources and NSR permits for new sources and modifications with emissions equal to or greater than a set of thresholds.
  - Thresholds (for attainment areas):
    - 10 tpy for CO, NOx, SO2, PM
    - 5 tpy for VOC, PM_{10}
    - 3 tpy for PM_{2.5}
    - 2 tpy for H2S
    - Others

- EPA has proposed that, for true minor O&G production sources, a FIP satisfies NSR requirements in lieu of site-specific permitting, a General Permit, or a Permit by Rule.
Federal Implementation Plan (FIP)

Why a FIP?

- Streamlines the authorization process;
- No in-depth case-by-case review by EPA;
- Allows O&G development to continue without waiting an unreasonable amount of time for minor source permits; and
- EPA feels it is sufficiently protective.
Applicability

• The FIP would apply to new and modified true minor O&G production sources in attainment and unclassifiable areas, however:
  – Cannot be used to establish synthetic minor status; and
  – EPA can still require a site-specific permit in cases where they feel the NAAQS may be threatened

• Covers the following equipment in the production segment: Engines, compressors, storage vessels, fugitives, dehydrators, completions, pneumatic controllers and pumps, and process heaters.
How it would work

- Compliance with six underlying regulations will constitute compliance with the Indian Country NSR Rule.
  - There is no “forced applicability” of the NSPS or MACT rules.
  - Underlying rules include: MACT DDDDD, MACT HH, NSPS Kb, NSPS IIII, and NSPS JJJJ, NSPS OOOOa.

- Requires registration, along with review of endangered species and historic properties
  - The latter is already a requirement under the Indian Country NSR Rule.
Submittals

• Deadlines
  – FIP Registrations and Site-Specific Permitting proposed to start October 3, 2016.
    • Current permitting kick-off date is March 2, 2016.
• Requirements for FIP Sources
  – Comply with the listed NSPS and MACT standards.
  – Submit a registration 30 days prior to commencing construction.
  – Complete an Endangered Species and Historic Properties Review.
    • This could be a hold-up, so plan ahead!
    • EPA has issued guidance for this.
Questions and Discussion

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